April 20, 2007 Comments

30 kW and Larger Interconnection Procedures Workgroup

Michigan Public Service Commission

This document contains comments on the following objectives:

1. Identify reasonable and achievable interconnection time deadlines.
2. Propose a system for determining whether interconnection costs are reasonable, actual costs.
3. Study the impacts and benefits of requiring utilities to consult with transmission providers when certain interconnection applications are filed (for distribution-level interconnections).
4. Investigate the impacts and benefits of requiring all generators to maintain an acceptable power factor.
5. Develop criteria for identification of areas of opportunity for distributed generation on each utility's distribution system.

Comment Summary

William Stockhausen

Thank you for the opportunity to comment.

In order to meet the upcoming RPS requirements the interconnection process for the 30 - 750 kW segment will have to be more streamlined and cost effective.

The following parameters need to be relaxed to stimulate interest and effect viability for small renewable power producers to come on line:

1) Extensive studies for engineering and systemic line effects that are costly and time consuming (doubly true with rotary machinery vs inverter type) are unnecessary. These kinds of studies aren't done in this power segment when the customer is a user rather than a generator.

2) Additional liability insurance can be dispensed with. There are no instances of linemen being injured due to a small power producer keeping the line energized. Protective relaying and lineman training make this a needless expense.

3) Some current stand by rates are exorbitant and also have a chilling effect for a co-gen or small power producer. Stand by rates need to be eliminated entirely - they fly in the face of the whole RPS effort.

4) Utility grade relays are expensive and in excess of the protection needed in this power segment. Industrial grade are sufficient.

Regards,

William Stockhausen
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Greg Sirna

I stated my thoughts to the MPSC last December. But I still think they apply to today's discussion. I will be going through an interconnection with Consumers Energy soon and I will than have a better understanding for the procedures involved. My biggest concern is the metering. Last time I interconnected with Consumers Energy I was charged $4,000 for the metering (on the secondary side of the line, 480 volts). When my project failed and the contract was canceled, the meters were removed (and more than likely used somewhere else as there was nothing wrong with them), yet no money was returned to me. So what did I pay for? This is a typical utility tactic. Utility grade controls vs industrial grade controls for projects under 750 kws is an other mater that needs attention. There should be standardized components available. As I said before the MPSC needs to walk through an interconnection of there own to experience first hand the Utility tactics to keep us off the grid.

Dec. 19, 2006
My thoughts on interconnection with the utilities are as follows: The cost associated with just the application of the interconnection with the utilities adds a burden for the small systems. The controls for the generators between the customers and the utilities need to be simple industrial grade not utility grade. The metering for the system should not be complicated nor expensive. The utility should not be able to charge $4000 for a set of meters that they retain ownership of. The interconnection package should not be designed to cause the project to fail as the utility does not want these project to make power as it is not in their financial self interest to let others make and sell power. The one line drawings for interconnection should be relegated to the project and simple with not everything including the kitchen sink in it. There are a host of issues that will arise when doing a project, the commission should implement their own small project to see first hand the stalling overburdening tactics of the utilities. Thank You Greg Sirna Centreville Hydro

MICHIGAN REGULATED ELECTRIC INDUSTRY COMMENTS ON OBJECTIVES OF 30 kW AND LARGER INTERCONNECTION PROCEDURES WORKGROUP

These informal comments are submitted by the Michigan Electric and Gas Association on behalf of Michigan regulated electric utilities including MEGA members, the electric distribution Cooperatives, The Detroit Edison Company and Consumers Energy Company. The MPSC Staff (Staff) published a set of proposed objectives for a working group and requested initial proposals by interested parties on how to achieve the objectives. This working group relates to the interconnection procedures for projects sized at 30 kW and larger. The initial comments were requested by Friday, April 20, 2007.

The following specific objectives were proposed:

1. Identify reasonable and achievable interconnection time deadlines.
2. Propose a system for determining whether interconnection costs are reasonable, actual costs.
3. Study the impacts and benefits of requiring utilities to consult with transmission providers when certain interconnection applications are filed (for distribution-level interconnections).
4. Investigate the impacts and benefits of requiring all generators to maintain an acceptable power factor.
5. Develop criteria for identification of areas of opportunity for distributed generation on each utility's distribution system.

The following initial comments on each of these objectives are provided on behalf of the industry group. The workgroup process will provide the opportunity for more detailed discussion among interested parties and more detailed proposals.

Objective 1: **Identify reasonable and achievable interconnection time deadlines.**

The investigation and comments in MPSC Case No. U-15113 indicated a need to reconsider the time deadlines in the Michigan interconnection rules. This will require discussion among all participants in the working group. The deadlines should account for the impact of long lead times for ordering equipment and making system modifications, if needed to complete an interconnection. Although the smallest projects (under 10 kW) can usually be addressed in a more expedited time frame, the time deadlines for other projects 30 kW and larger are typically subject to site specific work requirements and other matters (right-of-way, equipment availability, labor, operating agreement, testing) that may not directly correlate with the project size categories used in the rules. Utilities may be able to stock some items of equipment with long lead times. Depending on the circumstances, time requirements could extend out to six months or more.

The conduct of a pre-application meeting between the utility and interconnection applicant should facilitate more rapid interconnections and exchange of necessary information.

No overall deadline "clock" provision should start until a completed application is submitted and sufficient time should be allowed for the initial review of the application for completeness. For example, notification of receipt of the application in three business days would be the first step and then notification of an incomplete application with identification of the missing information would be required in ten business days. Only after all the missing information is provided would the "clock start" on the completion deadlines.

Other items which would facilitate timely completion of interconnections would include development of the approved equipment lists (relays), conceptual cost estimates based on generic interconnection parameters (subject to change based on actual circumstances for a specific project), and possibly a down payment for the engineering study and ordering materials made prior to execution of the interconnection agreement. A letter of intent could be considered for this last item.

One useful framework for discussion would be the "Wisconsin PSC 119" rules for interconnecting distributed generation facilities, submitted with these comments for informational purposes.

Objective 2: **Propose a system for determining interconnection costs are reasonable (actual costs)**

Further discussion and possible clarification of Objective 2 may be necessary. Utilities already charge customers the actual cost of modifications for an interconnection project. The process involves billing based on scope of project for materials and labor in a manner similar to customer line extensions. The use of utility overheads in this practice is consistent with approved MPSC accounting practices. Utilities are willing to provide actual detailed cost breakdowns based on major components of the project such as the easement, materials and labor. Customers are not permitted to perform work on utility assets.

Objective 3: **Study impacts and benefits of requiring utilities to consult with transmission providers when certain interconnection applications are filed (for distribution-level interconnections)**

Many or even most generator projects connecting at the distribution level would not impact the transmission system or adjacent distribution system. If, however, the interconnection project is large enough to affect these other systems, the providers should be consulted. The smaller projects (likely those under 2 MW) are less likely to impact other systems (although they could) and utilities suggest considering projects under 2 MW as a cutoff point for requiring the independent power producer to consult with the affected transmission or distribution system. Further, each project is evaluated to determine the impact of capacity needs, flow back potential, effects on connected distribution systems, and upstream coordination in relation to the transmission system.

Utilities will notify the transmission provider of potential impacts to the transmission system; however, the independent power producer should apply with the transmission provider as well as the utility, where appropriate (i.e. 2 MW or more). The MISO tariff governs the payment of cost of transmission system improvements by the project developer to the transmission provider.

Objective 4: **Investigate the impacts and benefits of requiring all generators to maintain an acceptable power factor.**

Unity (1.0) power factor on the high side of the step up transformer should be the base requirement for all interconnected generator projects. This is consistent with recommendations contained in the document "Final Report on the August 14, 2003 Blackout in the U.S. and Canada: Causes and Recommendations" (April, 2004) prepared by the U.S. – Canada Power System Outage Task Force.

The standards could provide for mutual agreement on deviation from the base requirement. If a project deviates from the unity base, the consequences can be additional VAR regulation (capacitors, inductors) required for the system at the developer's cost. A low or high power factor appears as load on the system and could affect the function of existing regulators, capacitor banks, etc.

Objective 5: **Develop criteria for identification of areas of opportunity for distributed generation on each utility's distribution system**

This objective will require more discussion and clarification. The suitability of location might best be left to discussions at the pre-application meetings for a specific project.

General public identification of such areas may create concerns regarding security and terrorism. It is unwise to make too much knowledge of the utility system function available in a public manner.

The large size and dynamic nature of utility distribution systems makes this a difficult task. Changes to the system from storm damage, capacity planning and other modifications could alter the "areas of opportunity" over time.

Utilities have a valid concern with possible liability claims based on performance of a project after selection of the optimal location. However, there could be feedback in the discussions regarding the best choice among several locations presented by the developer for a project.

Comments compiled for:

April 20, 2007

MICHIGAN ELECTRIC AND GAS ASSOCIATION
MICHIGAN ELECTRIC COOPERATIVE ASSOCIATION
CONSUMERS ENERGY COMPANY
THE DETROIT EDISON COMPANY

Chapter PSC 119

RULES FOR INTERCONNECTING DISTRIBUTED GENERATION FACILITIES

Subchapter I — General

PSC 119.01 Scope. This chapter implements s. 196.496, Stats. It applies to all DG facilities with a capacity of 15 MW or less that are interconnected, or whose owner seeks to have interconnected, to an electric public utility's distribution system. It also applies to all electric public utilities to whose distribution systems a DG facility is interconnected, or to which interconnection is sought. These rules establish uniform statewide standards for the interconnection of DG facilities to an electric distribution system.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.02 Definitions. In this chapter:

(1) "ANSI" means American National Standards Institute.

(2) "Applicant" means the legally responsible person applying to a public utility to interconnect a DG facility to the public utility's distribution system.

(3) "Application review" means a review by the public utility of the completed standard application form for interconnection, to determine if an engineering review or distribution system study is needed.

(4) "Category 1" means a DG facility of 20 kW or less.

(5) "Category 2" means a DG facility of greater than 20 kW and not more than 200 kW.

(6) "Category 3" means a DG facility of greater than 200 kW and not more than 1 MW.

(7) "Category 4" means a DG facility of greater than 1 MW and not more than 15 MW.

(8) "Certified equipment" means a generating, control or protective system that has been certified by a nationally recognized testing laboratory as meeting acceptable safety and reliability standards.

(9) "Commission" means the public service commission of Wisconsin.

(10) "Commissioning test" means the process of documenting and verifying the performance of a DG facility so that it operates in conformity with the design specifications.

(11) "Customer" means any person who is receiving electric service from a public utility's distribution system.

(12) "DG" means distributed generation.

(13) "DG facility" has the meaning given in s. 196.496 (1), Stats.

(14) "Distribution feeder" means an electric line from a public utility substation or other supply point to customers that is operated at 50 kV or less, or as determined by the commission.

(15) "Distribution system" means all electrical wires, equipment, and other facilities owned or provided by a public utility that are normally operated at 50 kV or less.

(16) "Distribution system study" means a study to determine if a distribution system upgrade is needed to accommodate the proposed DG facility and to determine the cost of any such upgrade.

(17) "Engineering review" means a study that may be undertaken by a public utility, in response to its receipt of a completed standard application form for interconnection, to determine the suitability of the installation.

(18) "Fault" means an equipment failure, conductor failure, short circuit, or other condition resulting from abnormally high amounts of current from the power source.

(19) "IEEE" means Institute of Electrical and Electronics Engineers.

(20) "Interconnection" means the physical connection of a DG facility to the distribution system so that parallel operation can occur.

(21) "Interconnection disconnect switch" means a mechanical device used to disconnect a DG facility from a distribution system.

(22) "Inverter" means a machine, device, or system that converts direct current power to alternating current power.

(23) "Islanding" means a condition on the distribution system in which a DG facility delivers power to customers using a portion of the distribution system that is electrically isolated from the remainder of the distribution system.

(24) "kV" means kilovolt.

(25) "kW" means kilowatt.

(26) "Material modification" means any modification that changes the maximum electrical output of a DG facility or changes the interconnection equipment, including:

(a) Changing from certified to non−certified devices.

(b) Replacing a component with a component of different functionality or UL listing.

(27) "MW" means megawatt.

(28) "Nationally recognized testing laboratory" means any testing laboratory recognized by the U.S. Department of Labor Occupational Safety and Health Administration's accreditation program.

Note: A list of nationally recognized testing laboratories is available at www.osha.gov/dts/otpca/nrtl/index.html.

(29) "Network service" means 2 or more primary distribution feeders electrically connected on the low voltage side of 2 or more transformers, to form a single power source for any customer.

(30) "Parallel operation" means the operation, for longer than 100 milliseconds, of an on−site DG facility while the facility is connected to the energized distribution system.

(31) "Paralleling equipment" means the generating and protective equipment system that interfaces and synchronizes a DG facility with the distribution system.

(32) "Point of common coupling" means the point where the electrical conductors of the distribution system are connected to the customer's conductors and where any transfer of electric power between the customer and the distribution system takes place.

(33) "Public utility" has the meaning given in s. 196.01 (5), Stats.

(34) "Standard application form" means PSC Form 6027 for Category 1 DG facilities or PSC Form 6028 for Category 2 to 4 DG facilities.

(35) "Standard interconnection agreement" means PSC Form 6029 for Category 1 facilities or PSC Form 6030 for Category 2 to 4 DG facilities.

Note: A copy of PSC Forms 6027 to 6030 can be obtained at no charge from your local electric utility or from the Public Service Commission, PO Box 7854, Madison, WI 53707−7854.

(36) "Telemetry" means transmission of DG operating data using telecommunications techniques.

(37) "UL" means Underwriters Laboratory.

(38) "Working day" has the meaning given in s. 227.01 (14), Stats.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

Subchapter II — General Requirements

PSC 119.03 Designated point of contact. Each public utility shall designate one point of contact for all customer inquiries related to DG facilities and from which interested parties can obtain installation guidelines and the appropriate standard commission application and interconnection agreement forms. Each public utility shall have current information concerning its DG point of contact on file with the commission.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.04 Application process for interconnecting DG facilities. Public utilities and applicants shall complete the following steps regarding interconnection applications for all classes of DG facilities, in the order listed:

(1) The public utility shall respond to each request for DG interconnection by furnishing, within 5 working days, its guidelines and the appropriate standard application form.

(2) The applicant shall complete and submit the standard application form to its public utility.

(3) Within 10 working days of receiving a new or revised application, the public utility shall notify the applicant whether the application is complete.

(4) Within 10 working days of determining that the application is complete, the public utility shall complete its application review. If the public utility determines, on the basis of the application review that an engineering review is needed, it shall notify the applicant and state the cost of that review. For Categories 2 and 3, the cost estimate shall be valid for one year. For Category 4, the time period shall be negotiated but may not exceed one year. If the application review shows that an engineering review is not needed, the applicant may install the DG facility and need not complete the steps described in subs. (5) to (9).

(5) If the public utility determines on the basis of the application review that an engineering review is needed, upon receiving from the applicant written notification to proceed and receipt of applicable payment from the applicant, the public utility shall complete an engineering review and notify the applicant of the results within the following times:

(a) Category 1 DG application, 10 working days.

(b) Category 2 DG application, 15 working days.

(c) Category 3 DG application, 20 working days.

(d) Category 4 DG application, 40 working days.

(6) If the engineering review indicates that a distribution system study is necessary, the public utility shall include, in writing, a cost estimate in its engineering review. The cost estimate shall be valid for one year and the applicant shall have one year from receipt of the cost estimate in which to notify the public utility to proceed, except for a Category 4 DG application, in which case the time period shall be negotiated, but may not extend beyond one year. Upon receiving written notification to proceed and payment of the applicable fee, the public utility shall conduct the distribution system study.

(7) The public utility shall within the following time periods complete the distribution system study and provide study results to the applicant:

(a) Category 1 DG application, 10 working days.

(b) Category 2 DG application, 15 working days.

(c) Category 3 DG application, 20 working days.

(d) Category 4 DG application, 60 working days unless a different time period is mutually agreed upon.

(8) The public utility shall perform a distribution system study of the local distribution system and notify the applicant of findings along with any distribution system construction or modification costs to be borne by the applicant.

(9) If the applicant agrees, in writing, to pay for any required distribution system construction and modifications, the public utility shall complete the distribution system upgrades and the applicant shall install the DG facility within a time frame that is mutually agreed upon. The applicant shall notify the public utility when project construction is complete.

(10) (a) The applicant shall give the public utility the opportunity to witness or verify the system testing, as required in s. PSC 119.30 or 119.31. Upon receiving notification that an installation is complete, the public utility has 10 working days, for a Category 1 or 2 DG project, or 20 working days, for a Category 3 or 4 DG project, to complete the following:

1. Witness commissioning tests.

2. Perform an anti−islanding test or verify the protective equipment settings at its expense.

3. Waive its right, in writing, to witness or verify the commissioning tests.

(b) The applicant shall provide the public utility with the results of any required tests.

(11) The public utility may review the results of the on−site tests and shall notify the applicant within 5 working days, for a Category 1 DG project, or within 10 working days, for a Category 2 to 4 DG project, of its approval or disapproval of the interconnection. If approved, the public utility shall provide a written statement of final acceptance and cost reconciliation. Any applicant for a DG system that passes the commissioning test may sign a standard interconnection agreement and interconnect. If the public utility does not approve the interconnection, the applicant may take corrective action and request the public utility to reexamine its interconnection request.

(12) A standard interconnection agreement shall be signed by the applicant and public utility before parallel operation commences.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.05 Insurance and indemnification. (1) An applicant seeking to interconnect a DG facility to the distribution system of a public utility shall maintain liability insurance equal to or greater than the amounts stipulated in Table 119.05−1, per occurrence, or prove financial responsibility by another means mutually agreeable to the applicant and the public utility. For a

DG facility in Category 2 to 4, the applicant shall name the public utility as an additional insured party in the liability insurance policy.

Table 119.05−1

Category	Generation Capacity	Minimum Liability Insurance Coverage
1	20 kW or less	$300,000
2	Greater than 20 kW to 200 kW	$1,000,000
3	Greater than 200 kW to 1 MW	$2,000,000
4	Greater than 1 MW to 15 MW	Negotiated

(2) Each party to the standard interconnection agreement shall indemnify, hold harmless and defend the other party, its officers, directors, employees and agents from and against any and all claims, suits, liabilities, damages, costs and expenses resulting from the installation, operation, modification, maintenance or removal of the DG facility. The liability of each party shall be limited to direct actual damages, and all other damages at law or in equity shall be waived.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.06 Modifications to the DG facility. The applicant shall notify the public utility of plans for any material modification to the DG facility by providing at least 20 working days of advance notice for a Category 1 DG facility, 40 working days for Category 2 DG facility, and 60 working days for a Category 3 or 4 DG facility. The applicant shall provide this notification by submitting a revised standard application form and such supporting materials as may be reasonably requested by the public utility. The applicant may not commence any material modification to the DG facility until the public utility has approved the revised application, including any necessary engineering review or distribution system study. The public utility shall indicate its written approval or rejection of a revised application within the number of working days shown in the table below. Upon completion of the application process, a new standard interconnection agreement shall be signed by both parties prior to parallel operation. If the public utility fails to respond in the time specified in Table 119.06−1, the completed application is deemed approved.

Table 119.06−1

Category	Generation Capacity after Modification	Working Days for Utility's Response to Proposed Modifications
1	20 kW or less	20
2	Greater than 20 kW to 200 kW	40
3	Greater than 200 kW to 1 MW	60
4	Greater than 1 MW to 15 MW	60

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.07 Easements and rights−of−way. If a public utility line extension is required to accommodate a DG interconnection, the applicant shall provide, or obtain from others, suitable easements or rights−of−way. The applicant is responsible for the cost of providing or obtaining these easements or rights of way.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.08 Fees and distribution system costs.

(1) Upon receiving a standard application form, the public utility shall specify the amount of any engineering review or distribution system study fees. Application fees shall be credited toward the cost of any engineering review or distribution system study. The applicant shall pay the fees specified in Table 119.08, unless the public utility chooses to waive the fees in whole or in part.

Table 119.08−1

Category	Generation Capacity	Application Review Fee	Engineering Review Fee	Distribution System Study Fee
1	20 kW or less	None	None	None
2	Greater than 20 kW to 200 kW	$250	Max. $500	Max. $500
3	Greater than 200 kW to 1 MW	$500	Cost based	Cost based
4	Greater than 1 MW to 15 MW	$1000	Cost based	Cost based

(2) The public utility may recover from the applicant an amount up to the actual cost, for labor and parts, of any distribution system upgrades required. No public utility may charge a commissioning test fee for initial start−up of the DG facility. The utility may charge for retesting an installation that does not conform to the requirements set forth in this chapter.

(3) Costs for any necessary line extension shall be assessed pursuant to s. PSC 113.1005.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.09 Disconnection. A public utility may refuse to connect or may disconnect a DG facility from the distribution system only under any of the following conditions:

(1) Lack of approved standard application form or standard interconnection agreement.

(2) Termination of interconnection by mutual agreement.

(3) Non−compliance with the technical or contractual requirements.

(4) Distribution system emergency.

(5) Routine maintenance, repairs, and modifications, but only for a reasonable length of time necessary to perform the required work and upon reasonable notice.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.10 One−line schematic diagram.

(1) The applicant shall include a one−line schematic diagram with the completed standard application form. ANSI symbols shall be used in the one−line schematic diagram to show the following:

(a) Generator or inverter.

(b) Point where the DG facility is electrically connected to the customer's electrical system.

(c) Point of common coupling.

(d) Lockable interconnection disconnect switch.

(e) Method of grounding, including generator and transformer ground connections.

(f) Protection functions and systems.

(2) The applicant shall include with the schematic diagram technical specifications of the point where the DG facility is electrically connected to the customer's electrical system, including all anti−islanding and power quality protective systems. The specifications regarding the anti−islanding protective systems shall describe all automatic features provided to disconnect the DG facility from the distribution system in case of loss of grid power, including the functions for over/under voltage, over/under frequency, overcurrent, and loss of synchronism. The applicant shall also provide technical specifications for the generator, lockable interconnection disconnect switch, and grounding and shall attach the technical specification sheets for any certified equipment. The applicant shall include with the schematic diagram a statement by the manufacturer that its equipment meets or exceeds the type tested requirements for certification.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.11 Control schematics. For equipment not certified under s. PSC 119.26, the applicant shall include with the application a complete set of control schematics showing all protective functions and controls for generator protection and distribution system protection.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.12 Site plan. For all categories, the applicant shall include with the application a site plan that shows the location of the interconnection disconnect switch, adjoining street name, and the street address of the DG facility. For Category 2, 3, or 4 DG facilities, the site plan shall show the location of major equipment, electric service entrance, electric meter, interconnection disconnect switch, and interface equipment.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

Subchapter III — Design Requirements

PSC 119.20 General design requirements. (1) The applicant shall install protection devices to ensure that the current supplied by the DG facility is interrupted if a fault or other potentially dangerous event occurs on the distribution system. If such an event occurs and the public utility's distribution system is de−energized, any DG facility that is connected to this distribution system shall automatically disconnect. All DG facilities shall utilize protection devices that prevent electrically closing a DG facility that is out of synchronization with the distribution system.

(2) All installations shall include equipment circuit breakers, on the DG facility side of the point where the DG facility is electrically connected to the customer's electrical system, that are capable of interrupting the maximum available fault current. Equipment circuit breakers shall meet all applicable UL, ANSI, and IEEE standards.

(3) The public utility may require that the applicant furnish and install an interconnection disconnect switch that opens, with a visual break, all ungrounded poles of the interconnection circuit. The interconnection disconnect switch shall be rated for the voltage and fault current requirements of the DG facility, and shall meet all applicable UL, ANSI, and IEEE standards. The switch enclosure shall be properly grounded. The interconnection disconnect switch shall be accessible at all times, located for ease of access to public utility personnel, and shall be capable of being locked in the open position. The applicant shall follow the public utility's recommended switching, clearance, tagging, and locking procedures.

Note: Provisions of the Wisconsin Electrical Safety Code, Volume 2, ch. Comm 16 also apply to these installations.

(4) The applicant shall label the interconnection disconnect switch "Interconnection Disconnect Switch" by means of a permanently attached sign with clearly visible and permanent letters. The applicant shall provide and post its procedure for disconnecting the DG facility next to the switch.

(5) The applicant shall install an equipment grounding conductor, in addition to the ungrounded conductors, between the DG facility and the distribution system. The grounding conductors shall be available, permanent, and electrically continuous, shall be capable of safely carrying the maximum fault likely to be imposed on them by the systems to which they are connected, and shall have sufficiently low impedance to facilitate the operation of overcurrent protection devices under fault conditions. All DG transformations shall be multi−grounded. The DG facility may not be designed or implemented such that the earth becomes the sole fault current path.

Note: Grounding practices are also regulated by the Wisconsin Electrical Safety Code Volumes 1 and 2, as found in chs. Comm 16 and PSC 114.

(6) (a) Certified paralleling equipment shall conform to UL 1741 (January 17, 2001 Revision) or an equivalent standard as determined by the commission.

(b) Non−certified paralleling equipment shall conform to the requirements of IEEE 1547.

Note: The UL standards are available at http://ulstandardsinfonet.ul.com, and IEEE standards are available at http://ieee.org. They may also be viewed at the PSCW Library, 610 N. Whitney Way, Madison, WI.

(7) (a) All Category 1 and 2 DG facilities shall be operated at a power factor greater than 0.9.

(b) All Category 3 and 4 DG facilities shall be operated at unity power factor or as mutually agreed between the public utility and applicant.

(8) The DG facility shall not create system voltage or current disturbances that exceed the standards listed in subch. VII of ch. PSC 113.

(9) The applicant shall protect and synchronize its DG facility with the distribution system.

(10) Each DG facility shall include an automatic interrupting device that is listed with a nationally recognized testing laboratory and is rated to interrupt available fault current. The interrupting device shall be tripped by any of the required protective functions.

(11) An applicant for interconnection of a Category 3 or Category 4 facility shall provide test switches as specified by the public utility, to allow for testing the operation of the protective functions without unwiring or disassembling the equipment.

(12) The public utility may require a DG facility to be isolated from other customers by installation of a separate power transformer. When a separate transformer is required, the utility may include its actual cost in the distribution system upgrade costs. The applicant is responsible for supplying and paying for any custom transformer. This requirement does not apply to an induction−type generator with a capacity of 5 kW or less, or to other generating units of 10 kW or less that utilize a line−commutated inverter.

(13) The owner of a DG facility designed to operate in parallel with a spot or secondary network service shall provide relaying or control equipment that is rated and listed for the application and is acceptable to the public utility.

(14) For a Category 3 or Category 4 DG facility, the public utility may require that the facility owner provide telemetry equipment whose monitoring functions include transfer−trip function−

ality, voltage, current, real power (watts), reactive power (vars), and breaker status.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.25 Minimum protection requirements. (1) Each DG facility shall include protection and anti−islanding equipment to prevent the facility from adversely affecting the reliability or capability of the distribution system. The applicant shall contact the public utility to determine any specific protection requirements.

(2) The protective system functions, which may be met with microprocessor−based multifunction protection systems or discrete relays, are required. Protective relay activation shall not only alarm but shall also trip the generator breaker/contactor.

(3) In addition to anti−islanding protection, a DG facility shall meet the following minimum protection requirements:

(a) A Category 1 DG facility shall include:

1. Over/under frequency function.
2. Over/under voltage function.
3. Overcurrent function.
4. Ground fault protection.

(b) A Category 2, 3, or 4 DG facility shall include:

1. Over/under frequency function.
2. Over/under voltage function.
3. Overcurrent function.
4. Ground fault protection.
5. Synchronism check function.
6. Other equipment, such as other protective devices, supervisory control and alarms, telemetry and associated communications channel, that the public utility determines to be necessary. The public utility shall advise the applicant of any communications requirements after a preliminary review of the proposed installation.

(4) A DG facility certified pursuant to s. PSC 119.26 shall be deemed to meet the requirements of this section.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

Subchapter IV — Equipment Certification

PSC 119.26 Certified paralleling equipment. DG paralleling equipment that a nationally recognized testing laboratory certifies as meeting the applicable type testing requirements of UL 1741 (January 17, 2001 revision) is acceptable for interconnection, without additional protection systems, to the distribution system. The applicant may use certified paralleling equipment for interconnection to a distribution system without further review or testing of the equipment design by the public utility, but the use of this paralleling equipment does not automatically qualify the applicant to be interconnected to the distribution system at any point in the distribution system. The public utility may still require an engineering review to determine the compatibility of the distributed generation system with the distribution system capabilities at the selected point of common coupling.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.27 Non−certified paralleling equipment.

(1) Any DG facility that is not certified under s. PSC 119.26 shall be equipped with protective hardware or software to prevent islanding and to maintain power quality. The applicant shall provide the final design of this protective equipment. The public utility may review and approve the design, types of protective functions, and the implementation of the installation. The applicant shall own the protective equipment installed at its facility.

(2) The applicant shall calibrate any protective system approved under sub.(1) to the specifications of the public utility. The applicant shall obtain prior written approval from the public utility for any revisions to specified protection system calibrations.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

Subchapter V — Testing of DG Facility Installations

PSC 119.30 Anti−islanding test. The public utility may perform an anti−islanding test or observe the automatic shutdown before giving final written approval for interconnection of the DG facility. The anti−islanding test requires that the unit shut down upon sensing the loss of power on the distribution system. This can be simulated by either removing the customer meter or opening a disconnection switch while the generator is operating. Voltage across the customer side of the meter or disconnection switch shall be measured and must be observed to reduce to zero within two seconds after disconnection. The test shall be conducted with the generation as close to its full output as possible. If a voltage is sustained after the disconnection, approval of the installation shall not be given until corrective measures are taken with a subsequent successful shutdown test.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.31 Commissioning tests for paralleling equipment in Categories 2 to 4. The public utility shall provide the acceptable range of settings for the paralleling equipment of a Category 2, 3, or 4 DG facility. The applicant shall program protective equipment settings into this paralleling equipment. The public utility may verify the protective equipment settings prior to allowing the DG facility to interconnect to the distribution system.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.32 Additional test. The public utility or applicant may, upon reasonable notice, re−test the DG facility installation. The party requesting such re-testing shall bear the cost of the re-tests.

History: CR 03−003: cr. Register January 2004 No. 577, eff. 2−1−04.

PSC 119.40 Right to appeal. The owner of a generating facility interconnected or proposed to be interconnected with a utility system may appeal to the commission should any requirement of the utility service rules filed in accordance with the provisions of this chapter be considered excessive or unreasonable, Such appeal will be reviewed and the customer notified of the commission's determination.

History: CR 03−003: renum. from PSC 113.0208 and am. Register January 2004 No. 577, eff. 2−1−04.

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BY ELECTRONIC MAIL

April 20, 2007

Ms. Julie Baldwin, and
Mr. Brian Mills
Michigan Public Service Commission
6545 Mercantile Way
Lansing, Michigan 48909

In re: Docket 15113 - 30+ kW Interconnection Standards
Comments of American Transmission Company (ATC)

Dear Ms. Baldwin and Mr. Mills:

This letter responds to your invitation to comment on five policy objectives relating to interconnection standards for distribution-interconnected generators of 30 kW or greater.

In response to the Commission Staff's initial inquiry in Docket No. 15113, ATC urged that the distribution interconnected generator process specifically incorporate consultation with the transmission owner (TO) when generator interconnection with the distribution facilities is requested[1]. ATC noted that, even though generators are connected to the distribution system and not directly to the transmission system, some distribution interconnected generators can affect transmission system operation, reliability and safety.

ATC believes that in most cases where generation seeks to interconnect to distribution voltage facilities, ATC, as the TO, can assess interconnection impacts on the transmission system concurrent with utility studies, and only in some cases will additional study time or the possible construction of mitigation measures be needed to accommodate the interconnection. This aspect of the interconnection evaluation was not previously considered, and ATC is pleased that the suggestion is included (issue 3) for consideration and comment by all other parties.

In this docket, the Commission Staff has expanded its inquiry, and ATC is pleased to provide the following additional comments on the generation to distribution interconnection process.[2]

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[1] For purposes of its comments, ATC defines the terms "distribution" and "distribution facilities" to refer to any facilities that operate at voltages below 50kV. ATC defines the term "transmission" and "transmission facilities" to refer to facilities that operate at 50kV and above.

[2] ATC's comments here are to be taken in light of the Small Generator Interconnection Procedures under Attachment R of the Open Access Transmission and Energy Markets Tariff of the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and the requirements of the Federal Energy Regulatory Commission under the provisions of Order No. 2006. *Standardization of Small Generation Interconnection Agreements and Procedures*, Order No. 2006, 70 Fed.

Issues and ATC comments

Issue 1: Identify reasonable and achievable interconnection time deadlines.

Simply put, most generator-to-distribution (G-D) interconnections will require no transmission system impact study and would likely also not require any transmission impact mitigation. Some interconnections to distribution facilities, however, may have material, adverse impacts on the reliable operation of the adjacent, interconnected transmission system and would "trigger" the need for some form of transmission system impact study[3]. ATC would anticipate that such a study, in most cases, could be completed in 10 to 15 days, and could be done concurrent with the distribution company analysis of its system. A few interconnections, however, could require 90 or more days for impact and mitigation studies. Whether a more detailed analysis would be required, could likely be determined in the first 15 days following receipt of the necessary information concerning the generator and the proposed interconnection. With that determination, the transmission owner could also provide preliminary estimates of scope of the study, the cost of the study and time required to perform the detailed analysis.

ATC proposes two alternative threshold "tests" to determine when consultation with the TO by the distribution utility should be required. These tests are explained below (issue 3.) Distribution interconnected generation, especially in the lower [smaller] range of the 30 kW and above class, would not trigger either of the tests and review by the TP would be unnecessary.

The alternative threshold tests that ATC would recommend are:

Where a single generator request or the aggregation of existing and new generation, measured at the transmission-to-distribution (T-D) point of interconnection, exceeds a) the minimum distribution load or, b) the total connected generation is 10 MVA or greater, transmission consultation should be required. (These are the two alternate tests.) In these cases some, but not most, interconnection requests will require detailed study. [4]

In cases where more study is necessary, the TO should be able to provide a formal response to the distribution utility within 10-15 business days following receipt of certain basic generator-related information regarding the interconnection request. Depending on the analysis and the impact of the generation on the transmission system, the TO response may state that no further analysis is needed, or, alternatively, it would explain the need for further study(s) and provide an estimate of the time necessary to complete the more detailed analysis and the estimated cost of such analysis. Therefore, the rules governing interconnection of distribution-connected generator should recognize that there are limited instances where significantly longer study and construction times may be necessary.

The time to complete a more detailed study may, in some cases, exceed 90 days. This is reasonable because the analysis to be performed would be substantially the same as the analysis required for transmission-connected generation under the MISO Transmission and Energy Markets Tariff Attachments R and X. A study report documenting the system impact and the facilities required

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Reg. 34190 (June 13, 2005), 111 FERC ¶ 61,220 (2005), order on reh'g, Order No. 2006-A, 113 FERC ¶ 61,195, 70 Fed. Reg. 71760 (Nov. 30, 2005)

[3] ATC uses the term "impact study" in a manner similar to that used by the Midwest ISO in relation to all generator interconnections. Here, ATC anticipates that the typical system impact study would consider just the impact on transmission system reliability due to altered system flows and can be completed with 10 to 15 days. If a more complex study of the stability of the transmission system before and after the interconnection, as well as the ability of the system to withstand a fault, is required, additional time, as explained further in this reply, would be needed. In the event that the study shows that reliability would be adversely affected, the study would identify those means by which the adverse effects could be ameliorated or otherwise rectified.

[4] ATC notes the very wide range in size of generators that would be affected by "30kW and larger" guidelines. 30 kW is only about 3/1,000 of 10MVA – the size for generators to which a numerical threshold for guidelines recommended by ATC appears below. For reference, the typical land-based wind turbine is no larger than 2 MVA.

to mitigate the impact would be supplied to the distribution utility upon conclusion of the TO study. An example of a generator interconnection report prepared by ATC for a transmission interconnected generator can be found at:

http://oasis.midwestiso.org/documents/ATC/G583_Impact_Study.pdf

Adopting this approach is important for transmission system reliability purposes and is consistent with the interconnection process followed in connection with interconnecting directly to the transmission system. The commission should note that if a distribution-connected generator wants to offer energy into the MISO energy market or be designated as a network resource in the MISO energy market, the generator customer will be required to coordinate their request with the MISO directly according to MISO's tariff and procedures.

Issue 2: Propose a system for determining whether interconnection costs are reasonable, actual costs.

ATC understands the desire by some to have an identified, readily available and uniform process that could help small generators predict development time and costs for a new generator. Unless such a tool includes and explains a wide variation in possible costs of interconnections, it may only invite disputes when unusual circumstances arise. In ATC's experience, the impact that a generator may have on the system to which it interconnects is highly variable. While having a defined process is undoubtedly valuable, it is also valuable to insure that all interested parties have a clear understanding of the impact that a new generator may have on all elements of the interconnected distribution-transmission system as early as possible in the process, so that, in the event that there are significant impacts, they can be addressed and appropriately taken into account by all parties.

In the event that a more detailed study is required, the customer requesting the interconnection should be required to pay the actual costs incurred by the TO to perform the required impact study. Once it is determined, in the initial evaluation, that the generator interconnection may have an impact on the transmission system, the study ATC proposes would determine the nature and extent of those impacts caused by interconnection of the generator; as well as the mitigation measures, i.e., possible changes to the transmission system, that would be required. A study report documenting the system impact and the facilities required to mitigate the impact would be supplied to the distribution utility and to the interconnection customer.

Issue for future consideration

As described below under issue 3, additional cost for study and interconnection mitigation measures is likely to occur in relatively few cases – generally where larger generating units (or a series of smaller ones) are to be interconnected to the distribution system, but which cause transmission system impacts that require mitigation. In such cases, cost assignment depends on several variables, including: 1) whether the generation meets only local needs or exceeds local distribution loads; 2)whether the generator plans to sell into the market; and 3) whether the generation will be available as a network resource.

These characteristics influence the allocation of the cost of transmission system impacts and mitigation. Transmission system impact mitigation costs, i.e., the cost of modifying existing transmission facilities or constructing new facilities is important to the generator customer, the distribution company and the transmission owner. At a minimum, the Commission's rules relating to these costs should harmonize, to the greatest extent possible, with MISO and FERC cost allocation policies. The Commission should consider whether the construction of transmission-related facilities that are required by virtue of the distribution interconnection requires a further inquiry into how those costs are to be allocated among the interested parties.

Issue 3: Study the impacts and benefits of requiring utilities to consult with transmission providers when certain interconnection applications are filed (for distribution-level interconnections).

In the process being considered by the Commission, ATC believes that there are circumstances when the local distribution utility should be required to inform the TO of a new distribution-connected generator interconnection request. Although the typical distribution-connected generator will not adversely impact the transmission network, if a single generator or the aggregation of existing and new generation exceeds certain thresholds, a material impact to the transmission system may occur which would affect the reliable operation of the transmission system and potentially affect the ability of the TO to provide reliable service to the local distribution company. The transmission owner analysis can and should occur concurrently with the distribution utility's analysis.

ATC recommends the following thresholds, as measured at the Point of Interconnection between the transmission and distribution system (T-D POI), be used to determine when the local distribution utility should inform the TO of the generator interconnection request. Where the single generator request or the aggregation of existing and new generation, as a measured at the T-D POI, exceeds:

- The minimum distribution load or
- The total connected generation is 10 MVA or greater.

In these instances, additional study will likely be required.

These threshold tests were chose for the following reasons:

1. **Generation exceeds the minimum distribution load.**
   When distribution connected generation exceeds the minimum local load, power will be transmitted onto and through the transmission network. Since power will be flowing on the transmission grid, it is reasonable that the TO should be informed of the request and given time to ensure that there are no adverse impacts due to the distribution-connected generation. If there are adverse impacts as a result of the proposed interconnection, then the appropriate study and identification of mitigating changes to the transmission system need to be identified and installed before the generator is permitted to tender power to the interconnected distribution-transmission network.

2. **The total connected generation is 10 MVA or greater.**
   The 10 MVA level is a regional guideline for various generator testing and reliability matters. ATC is a member of the Midwest Reliability Organization (MRO), which is one of the North American Electric Reliability Corporation (NERC) regional reliability organizations created to implement and monitor compliance with the mandatory NERC Reliability Standards approved by the FERC. The MRO has approved various generator testing guidelines with a minimum 10 MVA threshold for transmission-connected generation to be reported for compliance purposes. This threshold was designed to identify generators that may adversely interact with the remainder of the transmission network .

ATC believes that both tests should be used primarily because the local load at many locations on the transmission network may exceed 10 MW (e.g., paper mills), therefore the use of only the minimum distribution load test would have the potential to permit substantial amounts of generation to become connected to the distribution portion of the interconnected distribution-transmission network and operated in parallel with the transmission network without the TO being permitted to study the impacts and determine if there are any reliability-related impacts associated with that interconnection. Application of both tests assures that such potential situations are identified and the potential reliability assessed in a timely and appropriate manner.

Applying both tests will likely avoid performing analysis on those generators that will not have a material adverse impact on the network, while at the same time identifying those generators that <u>may have such an impact</u> at the earliest possible time. ATC believes, that if those tests are adopted and employed, the most common planning analysis to be performed by the TO on an interconnection request is a steady-state power flow analysis of the thermal and voltage impacts that would be created by interconnecting the new generator. Although there is a potential for transmission system problems or generator instability with any generator interconnection, most interconnection requests covered by this docket will not require this more detailed analysis.

ATC recommends that any interconnection request exceeding either of these thresholds would require a review by the TO. Based on ATC's experience, a detailed analysis by the transmission owner will likely be required only in those instances where the second test, the 10 MVA threshold, is exceeded.

With detailed analysis required in only a few instances, the TO should typically be able to provide a formal response to the distribution utility within 10-15 business days after receiving the necessary information regarding the distribution-connected generator interconnection request. In the instances where the more detailed stability analysis is required (e.g., 10 MVA threshold), ATC would recommend that the TO be required in its response to indicate 1) the nature and extent of the analysis needed; 2) a request that the distribution utility provide the further detailed information required for this study; 3) an estimated cost of the study; and, 4) the expected timeframe to complete the study once the required data has been received. With this information, the distribution company and interconnection customer can evaluate whether to proceed with the interconnection.

In ATC's view, the customer requesting the interconnection should be required to pay the actual costs incurred by the TO to perform this more detailed study because the analysis is complex, time consuming and requires considerable expertise to perform, As ATC has noted, in its experience, the time to complete this more detailed study may exceed 90 days and the cost to complete the study may approach $50,000, which is reasonable given that this analysis would be no different than that required by the Midwest ISO tariff for transmission-connected generation (cf. MISO Transmission and Energy Markets Tariff Attachments R and X). A study report documenting the system impact and the facilities required to mitigate the impact would be supplied to the distribution utility and the generator customer.

Thank you for this opportunity to comment.

Sincerely,

/s/ Jay A. Porter

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